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Environmental Research Letters

LETTER

OPEN ACCESS

RECEIVED
12 March 2018

REVISED
18 April 2018

ACCEPTED FOR PUBLICATION
25 April 2018

PUBLISHED
14 May 2018

The changing sensitivity of power systems to meteorological drivers: a case study of Great Britain

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Keywords: climate variability, power system, wind power, peak demand, wind power curtailment

Abstract

The increasing use of intermittent renewable generation (such as wind) is increasing the exposure of national power systems to meteorological variability. This study identifies how the integration of wind power in one particular country (Great Britain, GB) is affecting the overall sensitivity of the power system to weather using three key metrics: total annual energy requirement, peak residual load (from sources other than wind) and wind power curtailment.

The present-day level of wind power capacity (approximately 15 GW) is shown to have already changed the power system's overall sensitivity to weather in terms of the total annual energy requirement, from a temperature- to a wind-dominated regime (which occurred with 6GW of installed wind power capacity). Peak residual load from sources other than wind also shows a similar shift. The associated changes in the synoptic- and large-scale meteorological drivers associated with each metric are identified and discussed. In a period where power systems are changing rapidly, it is therefore argued that past experience of the weather impacts on the GB power system may not be a good guide for the impact on the present or near-future power system.

1. Introduction

There is a global move towards the use of renewable generation to meet carbon reduction targets, with substantial growth in installed wind power generation proposed by 2040 [1]. Great Britain (GB) is one of the European leaders in wind power generation, with 16GW installed [2] and the potential for a further 24GW to be installed by 2030 in plausible near-future scenarios [3]. Wind power generation therefore now plays a key role in the GB electricity system, and this is set to increase markedly. GB is used in this study as an example of a power system where wind power generation is the dominant renewable generation source.

The intermittent nature of wind power generation creates new challenges compared to a system operating solely on traditional generation sources such as nuclear and fossil fuel. In particular, the addition of wind power capacity impacts on power system components that are not themselves directly weather sensitive (e.g. the volume of power produced and prices received by traditional power stations; [4–7]). The focus of this paper is the impact of increasing wind power capacity on GB Total Annual Energy Requirement (TAER, i.e. the total energy (in GWh) required from generators other than wind power), peak residual load (i.e. the maximum load demanded from generators other than wind power) and wind power curtailment. For convenience we refer to these as *compound system impacts.*

There is growing evidence that weather and climate have a significant impact on power systems. At seasonal time-scales (3-monthly) the North Atlantic Oscillation (NAO; a meteorological index measuring the pressure difference between Iceland and the Azores, [8]) has been shown to affect wind power generation [9–13], power demand [11], and even electricity prices [7] in regions of western Europe. Other modes of climate variability—such as the East Atlantic and

Scandinavian pattern—have also been shown to play a contributory role [13]. On daily to weekly timescales GB wind power capacity has been related to synoptic scale (approximately 1000 km) weather events termed *regimes*, with zonal (west-east) regimes resulting in highest aggregate wind power generation, and blocked regimes resulting in lowest aggregate wind power generation [14, 15]. There is general consensus in the literature that GB peak demand is associated with an area of high pressure in the vicinity of GB, consistent with low temperatures over GB [14, 16–18]. These previous studies of climate-energy interactions are, however, typically limited in two key respects. Firstly most studies have only considered fixed distributions of present or near future installed wind power capacity and therefore the impact of changing the wind power capacity is largely unknown. Secondly, most meteorological studies (e.g. [10, 12, 13, 15, 19]) neglect the *compound* nature of weather's impact on the power system, focussing only on the impact of weather on individual components such as wind power or demand.

Given the National Grid's most renewable intensive scenario suggests GB could invest heavily in both onshore and offshore wind power generation [3], it is important to understand if the meteorological conditions during high compound system impacts may change under future wind-power scenarios. The aim of this paper is therefore to characterise the meteorological conditions associated with the compound system impacts of weather on the GB power system, and to investigate how this meteorological sensitivity changes with increasing installed wind power capacity.

The methods used in this study to create and isolate weather-dependent power system metrics are described in section 2. Section 3 presents the meteorological conditions present during extreme conditions of each of the metrics, and section 4 summarises the main findings and implications of this work.

2. Methods

Following the approach of [4], self-consistent hourly records of wind power and demand are constructed from the MERRA reanalysis [20], and used to create Load Duration Curves (LDC's). LDC's are then used to calculate Total Annual Energy Requirement (TAER), peak load and wind power curtailment, enabling the weather conditions associated with variability in each metric to be identified. A full discussion of the models, metrics and their validation can be found in [4]. Each stage of the process and the metrics are, however, outlined briefly below.

2.1. Demand model

A daily-average weather-dependent demand time series is created using a temperature-based multiple linear regression model

$$\begin{aligned}\text{Demand}(t)=&\alpha_1+\alpha_2(t)+\alpha_3\sin(\omega t)\\&+\alpha_4\cos(\omega t)+\alpha_5 Te(t)+\alpha_6 Te^2(t)\\&+\sum_{k=7}^{8}\alpha_k WE(t)\\&+\sum_{l=9}^{12}\alpha_i WD(t)+\alpha_{13}\text{HOL}(t)\end{aligned} \quad (1)$$

Here α's represent regression coefficients, t is the daily time-step, sine and cosine terms are used to reflect the seasonal cycle of demand, with period, $\omega = 1/365$ days, WD, WE, and HOL are terms representing weekdays and weekends and national holidays respectively. GB daily-average 2 m temperature is taken from the MERRA reanalysis for use in the model, and is used to create effective temperature (Te):

$$Te(t) = \frac{1}{2}T(t) + \frac{1}{2}Te(t-1) \quad (2)$$

Hourly demand is created from the daily-mean demand by interpolation using prescribed diurnal cycle anomaly curves, created based on metered hourly demand from 2006–2015 from the National Grid [21]. For the purposes of our analysis, however, exogenous behavioural factors such as weekends, national holidays and economic activity are neglected (i.e. α_2 and α_7 to α_{13} are set to zero). This allows for clearer identification of the *weather conditions* associated with power system behaviour.

2.2. Wind power model

The wind power model from [22] is used to simulate hourly time series of GB aggregated wind power capacity factor from 1980–2015 (capacity factor is the percentage of wind energy produced compared to if all the turbines were operating at maximum output). The wind power model uses the 2 m, 10 m and 50 m wind speeds from the MERRA re-analysis [20]. Wind speeds are spatially interpolated onto the locations of the GB wind farms. A logarithmic vertical wind shear profile is then created from the 2 m, 10 m, and 50 m wind speeds at each wind farm location. These profiles are used to scale the 50 m wind speeds to wind turbine hub-heights (60–100 m). Wind speeds from each site are converted into wind power using a standardised wind power curve and aggregated across GB to produce an hourly capacity factor time series. The wind-power model reproduces GB national-total wind power output well in most cases. MERRA accurately reproduces the observed 10 m wind speeds (when compared to observational data) with a small systematic overestimation for wind speeds less than 6 ms^{-1} and a large underestimation for wind speeds greater than 20 ms^{-1}. Full details of the validation can be found in [22].

In order to investigate how the meteorological sensitivities of compound power system phenomena change with increasing installed wind capacity a series of wind power scenarios are defined:

- NO-WIND: No installed wind power capacity
- LOW: 15 GW of installed wind power capacity. This represents an approximate present day wind farm distribution
- MED: 30 GW of installed wind power capacity. This is approximately equivalent to the amount of installed capacity in 2025 from the National Grid's gone green scenario in [23].
- HIGH: 45 GW of installed wind power capacity. This is approximately equivalent to the amount of installed capacity in 2035 from the National Grid's gone green scenario in [23]

Scenarios LOW and MED assume a spatial distribution of wind farms unchanged from the present day (as in [22]) whereas for the HIGH scenario a substantial increase in offshore wind is assumed (as in [24]).

2.3. Load duration curves and power system metrics

LDC's are used to understand the combined demand-supply impact of weather on the power system. In this context, load can be thought of as the residual demand for power once wind power generation is removed (i.e. as residual-load). To form a LDC, each year of residual-load is converted into a cumulative frequency curve, showing the percentage of the year that a given load threshold is exceeded. A separate LDC is made for each year of meteorological data (January–December). Further details on the inter-annual variability of the LDC's and various power system relevant metrics can be found in [4].

An essential assumption in this study is that wind generation is given preference over other conventional generation types (such as coal or nuclear). This is a common approach within the analysis of power systems when seeking to explore the impact of increasing installed wind power capacity on the power system (e.g. [25–27]). For simplicity this study assumes that GB is an isolated system with no inter-connectors, and that the operational behaviour of each type of generation is constant throughout these scenarios.

In this study three power system metrics are considered:

- Total Annual Energy Requirement (TAER): The sum of the annual load to be met by conventional (i.e. non weather-driven) generation. This corresponds to the area under each LDC.
- Peak load requirement: The highest hourly loads recorded on the system over the 36 year period. A 3 day threshold has been applied so that the top 10 events are not associated with the same weather system.
- Wind power curtailment: The total volume of energy accumulated in consecutive hours when wind-power is greater than 70% of demand. The threshold of 70% is assumed to be an indicator of system stability limits associated with the penetration of non-synchronous generation (i.e. generation with large rotating parts to provide inertia; see [28] and [4] for a detailed discussion).

These metrics were chosen for analysis due to their broad relevance for power system operation. TAER helps to assess whether we are able to meet carbon mitigation targets and the overall requirement for generation from conventional sources, based on total annual energy use. On shorter timescales, understanding the synoptic weather-conditions present during extreme peak load events is relevant for planning of system reserve requirements and security of supply. Similarly, knowledge of the weather patterns present during curtailment events is useful due to their economic impact and the associated likelihood of transmission grid congestion.

3. Results

3.1. Meteorological conditions associated with GB total annual energy requirement

The spatial structure of the annual-mean 2 m temperature anomalies and annual-mean 10 m wind speed anomalies for the six years of highest TAER and six years of lowest TAER are shown in figure 1. In the NO-WIND scenario the years of highest TAER exhibit anomalously low temperatures over Central–Northern Europe and anomalously low wind speeds over North West Europe and the North East Atlantic (i.e. the predominant location of the North Atlantic storm track). A relatively weak pressure gradient is seen over Europe in the years of highest TAER. Conversely the years of lowest TAER exhibit anomalously warm temperatures over Central–Northern Europe, with near average wind speeds (anomalies of $<0.25\,\mathrm{ms}^{-1}$). A stronger pressure gradient is seen over Europe in the years of lowest TAER.

Figure 2 shows the strength of the correlation between 10 m wind-speed and TAER increases until approximately 15–25 GW of wind power generation is installed, with a very strong correlation seen between annual-mean 10 m wind speed and TAER beyond this point. The low correlation between annual-mean 2 m temperature and TAER, however, continues to decrease with increasing wind power capacity up to at least 45 GW.

An assessment has been made as to whether it is adequate to provide an annual analysis, or whether TAER is dominated by meteorological variability in a particular season. Figure 3 shows box plots of the mean residual-load in each meteorological season for each of the wind power scenarios. As expected, with increasing amounts of installed wind power capacity the total seasonal residual load decreases. In the NO-WIND scenario the largest total seasonal residual load is in winter. The bars on figure 3 show winter is also the season in which total residual load is most variable

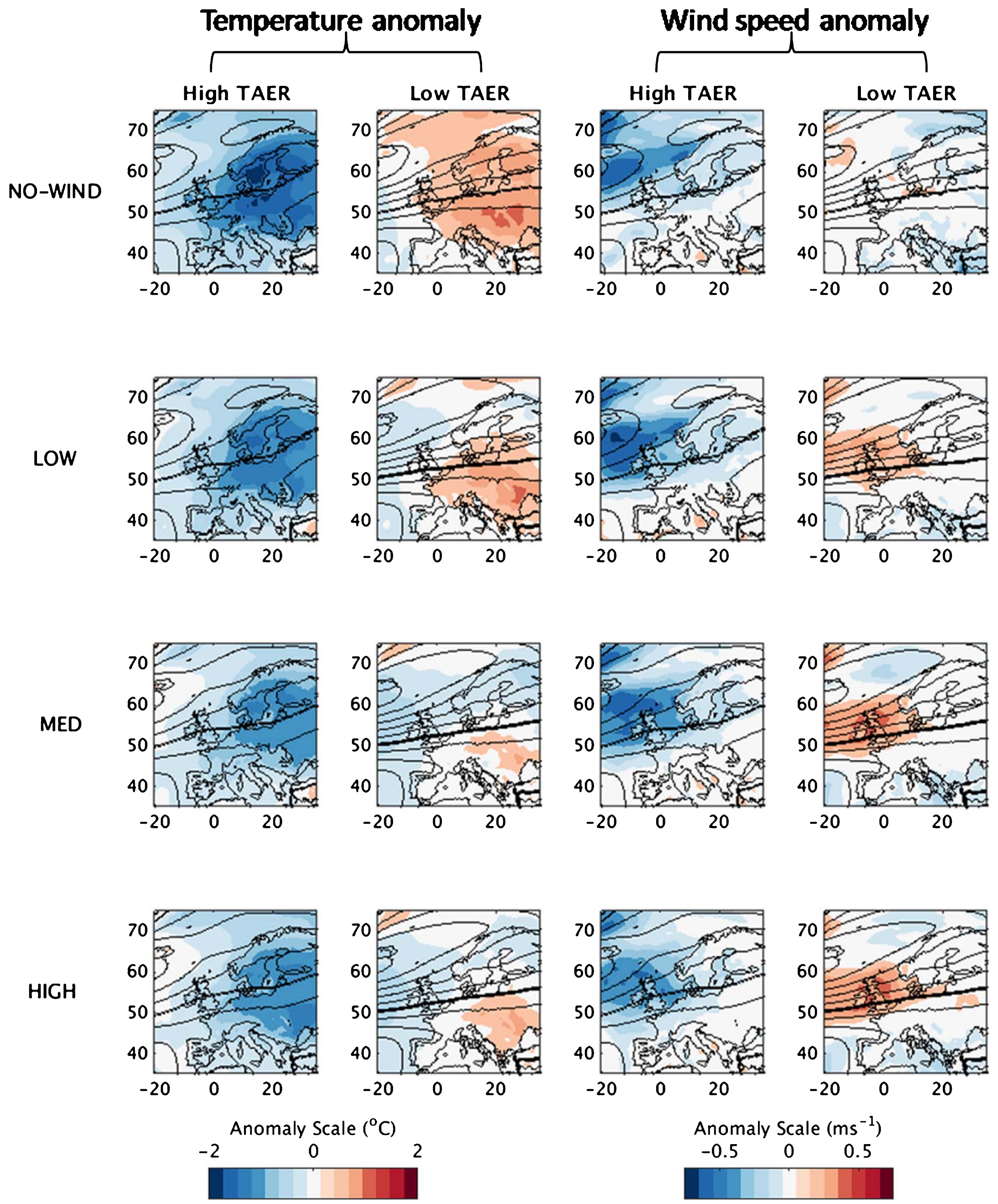

Figure 1. Annual-mean anomaly composites (from the 1980–2015 mean) of the six highest years of TAER (1st and 3rd columns) and six lowest years of TAER (2nd and 4th columns) for 2 m temperature (1st and 2nd columns) and 10 m wind speed (3rd and 4th columns) for the NO-WIND, LOW, MED and HIGH scenarios. Mean-sea-level-pressure contours are given in black at 2 hPa intervals, with the thick contour representing 1014 hPa.

over the 36 year period. In the LOW and MED wind power scenarios the total seasonal residual load is still largest in winter, but its dominance decreases and the variability in all seasons is increased compared to a system with no wind power capacity. In the HIGH scenario (figure 3(*d*)) the total seasonal residual load is comparable in all seasons, but load variability is highest in winter. In each scenario, the variability of TAER is therefore likely to be dominated by the variability of the winter seasonal load. Indeed, winter-mean 2 m temperature anomaly composites of the years of the most extreme TAER events look qualitatively similar to those for the annual-mean wind and temperature, though with winter-mean 2 m temperature anomalies typically 2–4 times stronger (compare figures 1 and 4). This suggests that winter weather dominates the variability of TAER.

In all of the wind power scenarios a strong negative correlation is seen between TAER and the winter NAO index, with correlation coefficients ranging from approximately −0.7 to −0.8 (figure 5). This is as expected as a more positive NAO index is associated with warmer and windier conditions and therefore reduced demand. Although the correlation coefficient between TAER and the NAO remains relatively constant, the percentage change in TAER between the

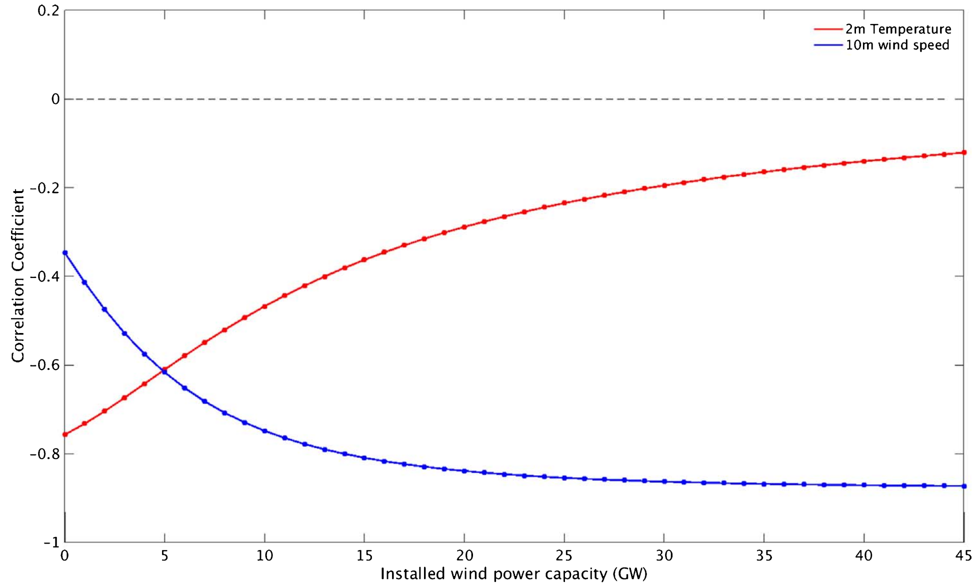

Figure 2. Correlation coefficient between annual-mean 2 m temperature and TAER (red) and annual-mean 10 m wind speed and TAER (blue) with varying levels of installed wind power generation from 0–45 GW. Correlations are calculated by taking an annual-average of the relevant meteorological field over GB (11.3 W–2.7 E and 50 N–59 N). Note the negative *y*-axis. Correlations between 10 m wind speed and TAER are statistically significant at all levels of installed wind power generation ($p < 0.05$). However correlations between 2 m temperature and TAER are only significant until 20 GW of wind power generation are installed.

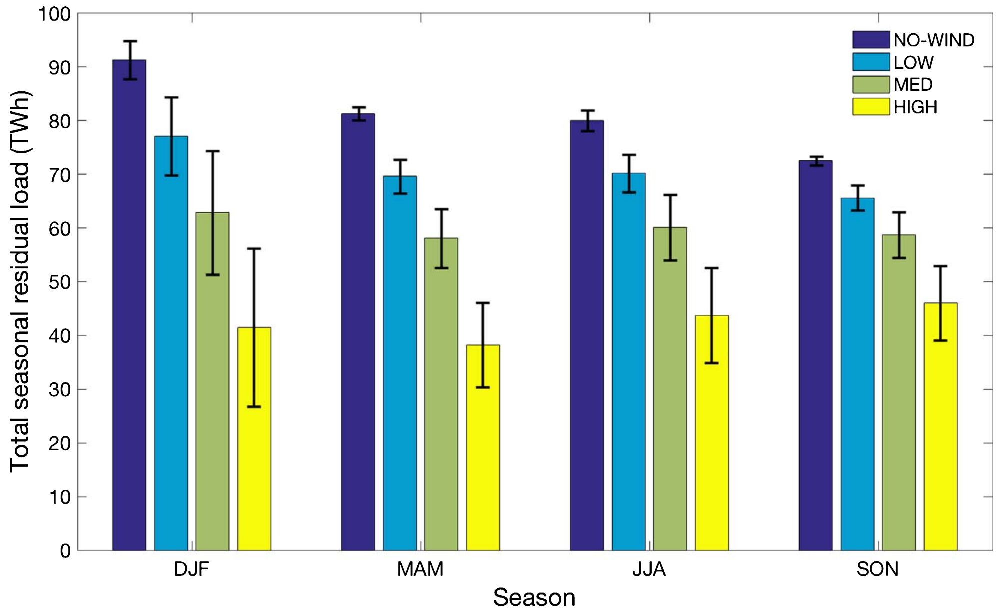

Figure 3. Total seasonal residual load (i.e. the maximum load demanded from generators other than wind power) over the period 1980–2015, with bars showing the inter-annual standard deviation for the NO-WIND, LOW, MED and HIGH scenarios.

two most extreme NAO years increases dramatically with increasing installed wind power capacity (figure 5(*b*)); note that the relative change in percentage terms looks very large as by construction TAER is reducing with increased installed wind power capacity). This shows that the strength of the relationship between low frequency modes of atmospheric variability and total system load is likely to increase with increasing wind power capacity. This also implies that an extreme NAO event would have a relatively larger impact on a GB power system with more installed wind power capacity.

3.2. Meteorological conditions associated with peak load

Anomaly composites of the top 10 peak load events are shown in figure 6 for all four wind power scenarios. Peak load events occur in winter in all wind power scenarios. In the NO-WIND scenario peak load is associated with high pressure centred to the north of GB, which results in an enhanced pressure gradient over GB. Anomalously low 2 m temperatures are seen over GB as well as parts of Central and Northern Europe, due to the local reversal of the climatological westerly

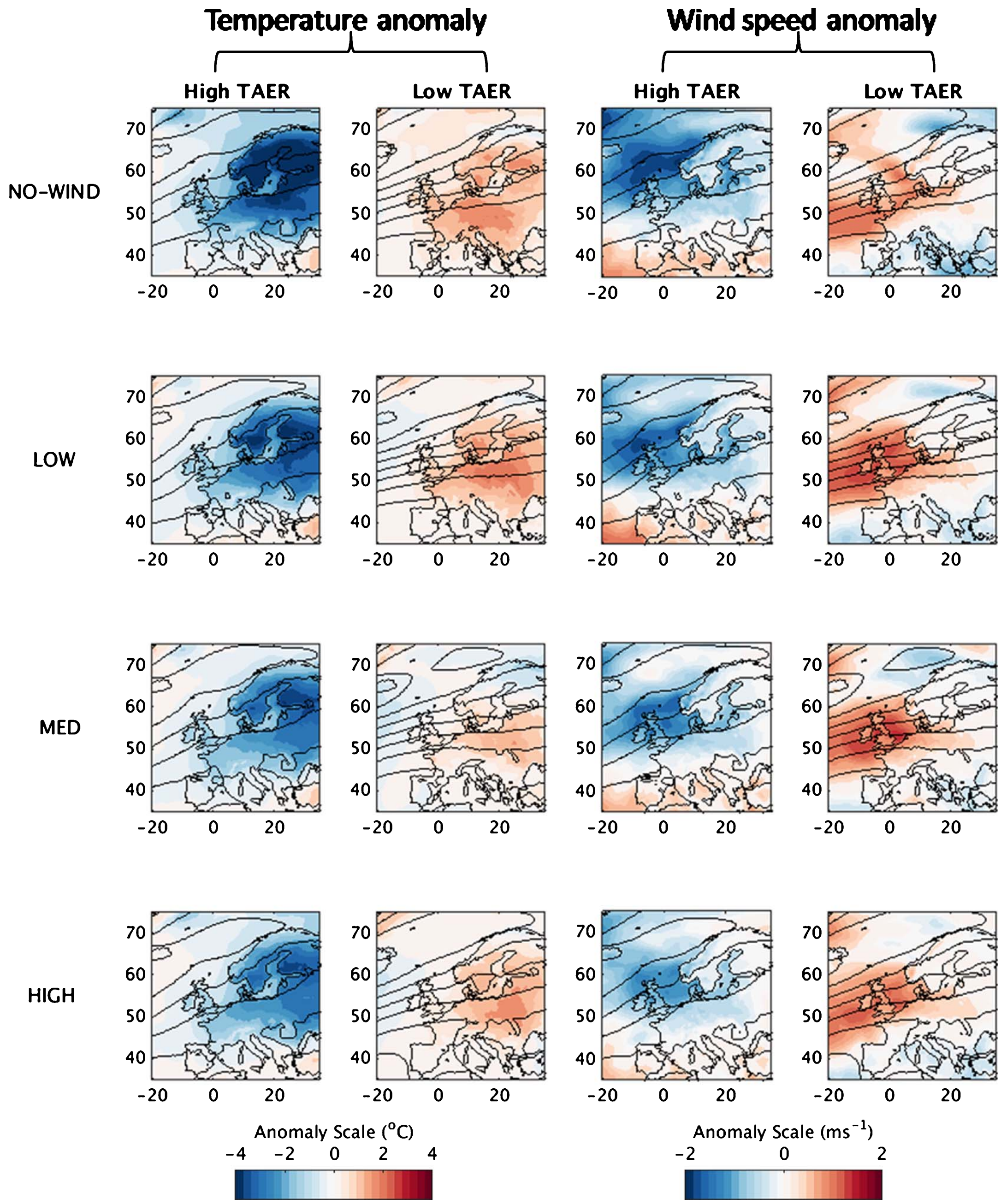

Figure 4. Winter-mean anomaly composites (from the 1980–2015 mean) of the six highest years of TAER (1st and 3rd columns) and six lowest years of TAER (2nd and 4th columns) for 2 m temperature (1st and 2nd columns) and 10 m wind speed (3rd and 4th columns) for the NO-WIND, LOW, MED and HIGH scenarios. Mean-sea-level-pressure contours are given in black at 4hPa intervals.

flow, consistent with the transport of cold, continental air towards GB as discussed in [18]. The wind speed anomalies seen for the peak load events in the NO-WIND scenario are relatively small compared to the temperature anomalies, with slightly below average winds. This shows that when no wind power generation is installed peak load is driven by anomalously cold weather irrespective of wind speed. These results are in agreement with [14] which explored the temperature and wind field during the top 5% of demand days over a similar period.

In the LOW scenario a subtle shift in location of the area of high pressure is seen relative to the NO-WIND scenario, so that there is no longer a strongly reversed pressure gradient over GB: instead the pressure gradient is almost zero. This results in a slight warming of the peak load temperature over GB (compared to the NO-WIND scenario), but also a decrease in wind speed. The airmass present over GB is now more stationary, with less cold air being transported from the continent. This suggests that while peak demand events in the LOW scenario are still associated with relatively cold weather in GB, these cold events must also have very low wind speeds. This is even more the case in the HIGH scenario where a closed high pressure contour is directly above the UK, resulting in somewhat milder temperatures but very low wind speeds.

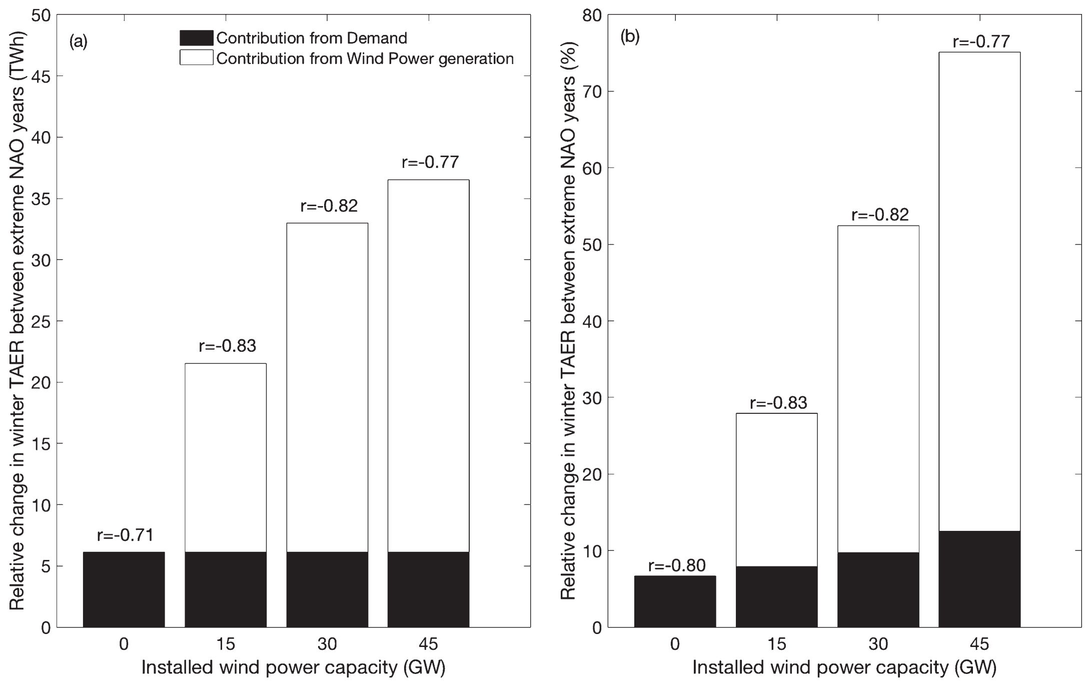

Figure 5. Relative change in winter Total Annual Energy Requirement (TAER) between the two most extreme NAO years in the period 1980–2015 for varying levels of installed wind power generation from 0–45 GW (($TAER_{NAO-} - TAER_{NAO+}$) / $TAER_{mean}$) for (*a*) the change in TWh and (*b*) the change in %. The correlation coefficient (*r*) between TAER and winter-mean NAO is given for each scenario as well as the contribution to each change from demand (black) and wind power generation (white). The NAO index is taken from *climate data guide.ucar.edu/climate − data/*

Figure 7 summarises how the weather sensitivity of peak load shifts as wind capacity is added. When no wind power is installed there is strong negative correlation ($r = -0.94$) between winter-mean temperatures and residual load during the top 10% of residual load events, and a weaker correlation with daily 10 m wind speed. Increased wind power capacity leads to a marked increase in the strength of the negative correlation between winter-mean 10 m wind speed and residual load during the top 10% peak residual load events, which then plateaus and begins to slightly decline once 15 GW of wind power is installed. In contrast, the correlation of peak load with winter-mean 2 m temperature monotonically decreases with installed wind power capacity. Overall there is a clear transition in the meteorological conditions associated with peak residual load, from a synoptic situation which is cold with near-average winds, to one which is still and less cold.

3.3. Meteorological conditions associated with wind power curtailment

Wind power curtailment events (defined as wind generation instantaneously exceeding 70% of total demand rather than including any level of network transmission constraints) do not occur in this study until 30GW of wind power generation is installed, therefore the analysis in this section is limited to the MED and HIGH scenarios.

Wind power curtailment events are most common in autumn. This can be understood by considering figure 8(*a*) which shows the climatological annual cycle of demand and the 90th percentile of wind power generation for multiple wind power scenarios. Both demand and wind power generation are at near maximum in winter, however, in September and October wind power generation approaches its winter maximum levels, whereas demand remains moderate.

The diurnal cycle of demand also plays an important role in limiting the duration of curtailment. In the MED scenario eight out of the ten most extreme curtailment events commence at 22:00 and end at around 16:00 the following day. The top-ten events vary in duration from 18 to 34 hours (with 201 hours of data in total over all 10 events). There is only one incidence of curtailment in the 36 year period which is greater than 24 hours long. It is therefore extremely rare for curtailment to occur at the peak of the diurnal cycle of demand in the MED scenario. The reasons for this are shown in figure 8(*b*). The climatological diurnal cycle of demand has a peak of approximately 42 GW therefore a very extreme wind event is needed for curtailment at the peak of the diurnal cycle of demand (with the 90th percentile wind power generation in the MED scenario still being considerably below the mean diurnal cycle). A situation with 50GW of installed wind power generation is included in figure 8(*b*) to show that extremely large volumes of wind power generation are required for wind power curtailment to become more common in autumn.

Figure 9 shows autumn-mean 2 m temperature and autumn-mean 10 m wind speed anomaly composites of the synoptic situation for the top 10 curtailment events

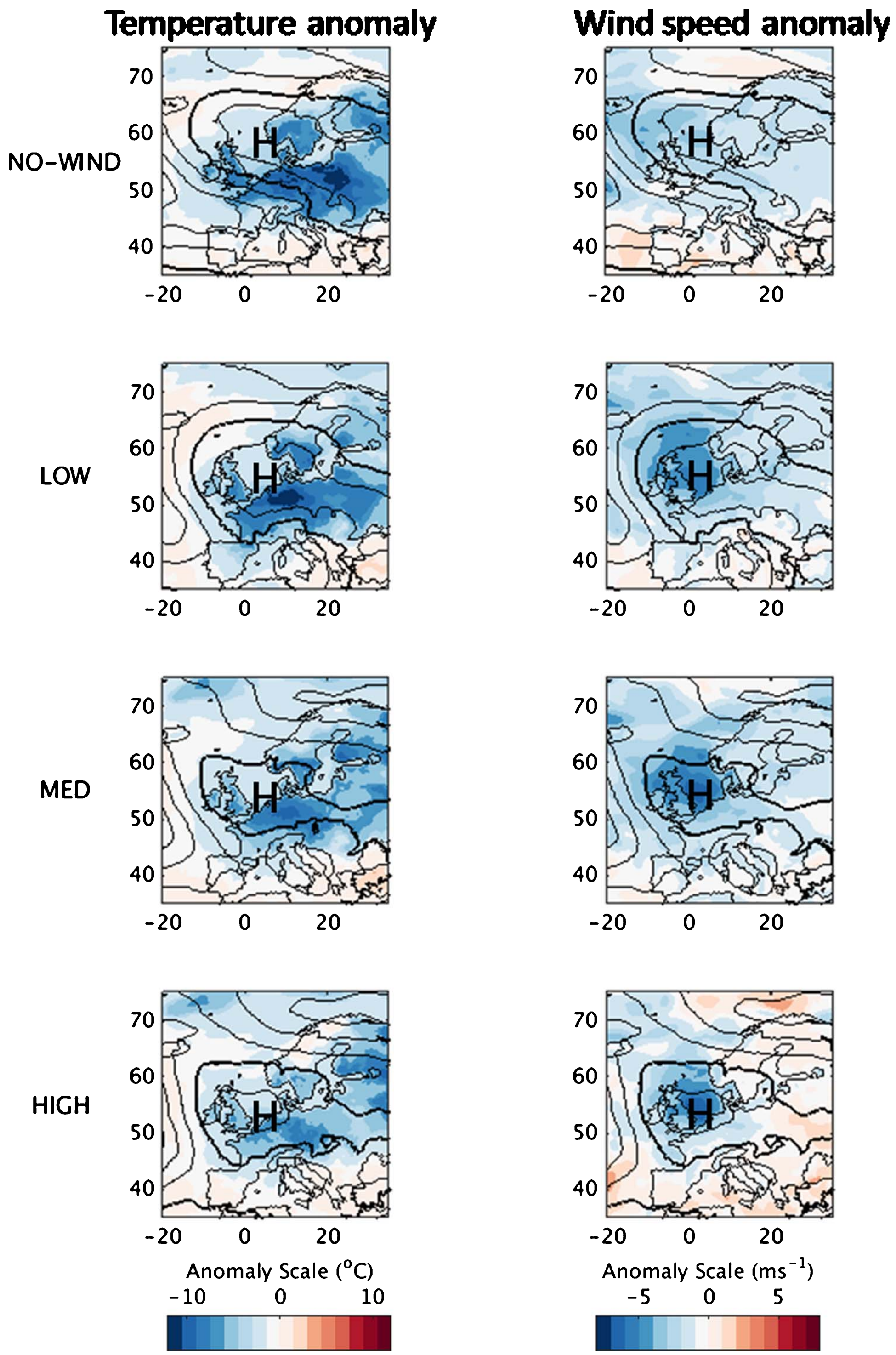

Figure 6. Anomaly composites of the mean of the ten most extreme peak loads from the 1980–2015 winter-mean. These are given for for 2 m temperature (first column) and 10 m wind speed (2nd column) for the NO-WIND, LOW, MED and HIGH scenarios. Mean-sea-level-pressure contours for the events are overlaid in black with a 4 hPa interval. The thick contour represents 1016 hPa. The 'H' represents the location of the centre of the region of high pressure.

from the MED and HIGH scenarios. In both scenarios extreme curtailment events are associated with near to average autumn daily 2 m temperatures over GB, and anomalously high 10 m wind speeds (therefore anomalously high wind power generation). The synoptic situation associated with this anomalously high wind power generation is low pressure to the north of GB, creating a strong horizontal pressure gradient in the region of anomalously high wind speeds and bringing strong westerly flow from the North Atlantic.

4. Conclusions

This study characterises the meteorological conditions associated with extreme weather-dependent power

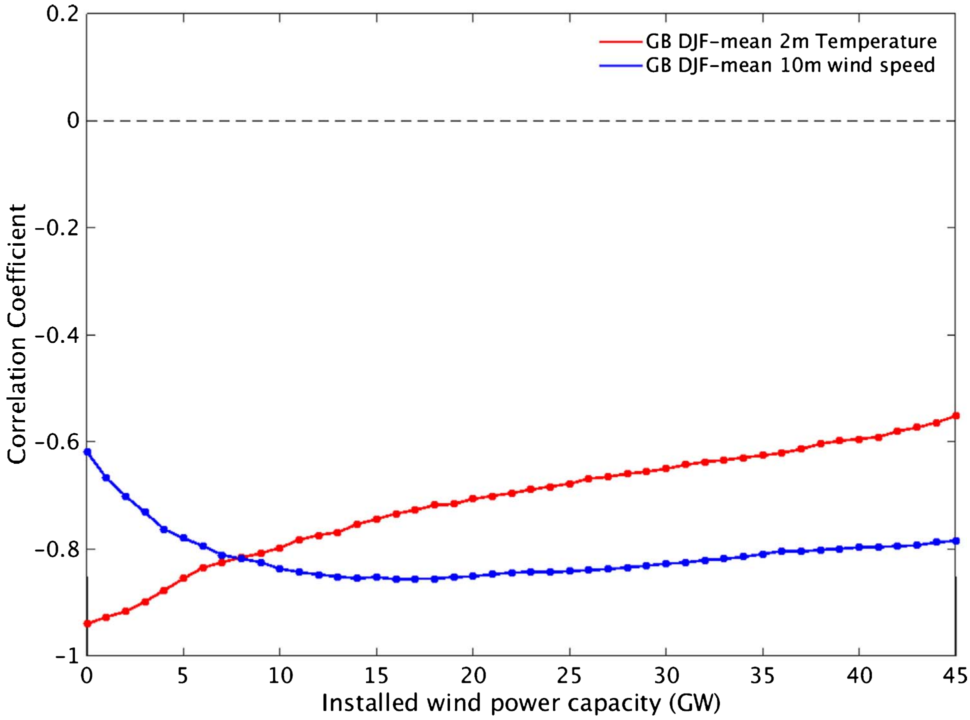

Figure 7. Correlation coefficient between winter-mean 2 m temperature and the top 10% of load (red) and winter-mean 10 m wind speed and the top 10% of load (blue) with varying levels of installed wind power generation from 0–45 GW. Correlations are calculated by taking an winter-average of the relevant meteorological field over GB (11.3W–2.7E and 50N–59N). Note the negative *y*-axis. Correlations are statistically significant at all levels of installed wind power generation ($p < 0.05$).

system impacts and analyses how the sensitivity of the power system to meteorological conditions is affected by the level of installed wind power.

A summary of the key results are given below:

- The weather conditions to which the GB power system is most strongly impacted are different depending on the amount of installed wind power capacity. The total energy generation required from traditional generation sources (i.e. non-wind) in the GB power system is already predominantly characterised by the variability in near-surface wind speed rather than temperature.
- In a system with no installed wind power capacity, the peak residual load from traditional generation is associated with anomalously low 2 m temperatures over Europe. This is usually associated with a high pressure centred to the north of GB, causing a reversal in the usual westerly flow. However, as larger volumes of wind power generation are installed (i.e. present levels and increasing) the peak residual load events tend to be associated with moderately low temperatures and very low wind speeds over GB, and high pressure centred directly over GB. This suggests need for generation adequacy analysis to shift from focusing on *wind power availability during peak load* towards a more integrated measure of *peak residual load*, as significantly different meteorological conditions are typically involved.
- Demand-limited curtailment events (where wind power generation exceeds 70% of demand) were found to be associated with low pressure systems, located to the north of GB, causing a strong horizontal pressure gradient and high wind power production. These events preferentially occurred during the autumn season where average wind generation is similar to its peak winter value, but demand remains moderate.

Overall, it is therefore clear that the GB may have already transitioned from a temperature-dominated to a wind-dominated weather sensitivity regime. One major consequence of this is that the meteorological sensitivity of the power system observed in past decades may be a poor guide to the future impacts of weather. It is worth noting that the wind speed anomalies seen in this study are strongly impacted by the location of the installed wind capacity. If investment was made on the borders of the exclusive economic zone this could result in different synoptic conditions being associated with the largest power system impacts.

The analysis of the meteorological conditions present during years of highest TAER also showed they occurred when annual-mean 2 m temperatures were anomalously low over Central–Northern Europe, i.e. that there was a strong spatial correlation in temperature. This suggests that in years where GB demand is high, other European countries are also experiencing cold conditions and therefore likely enhanced demand

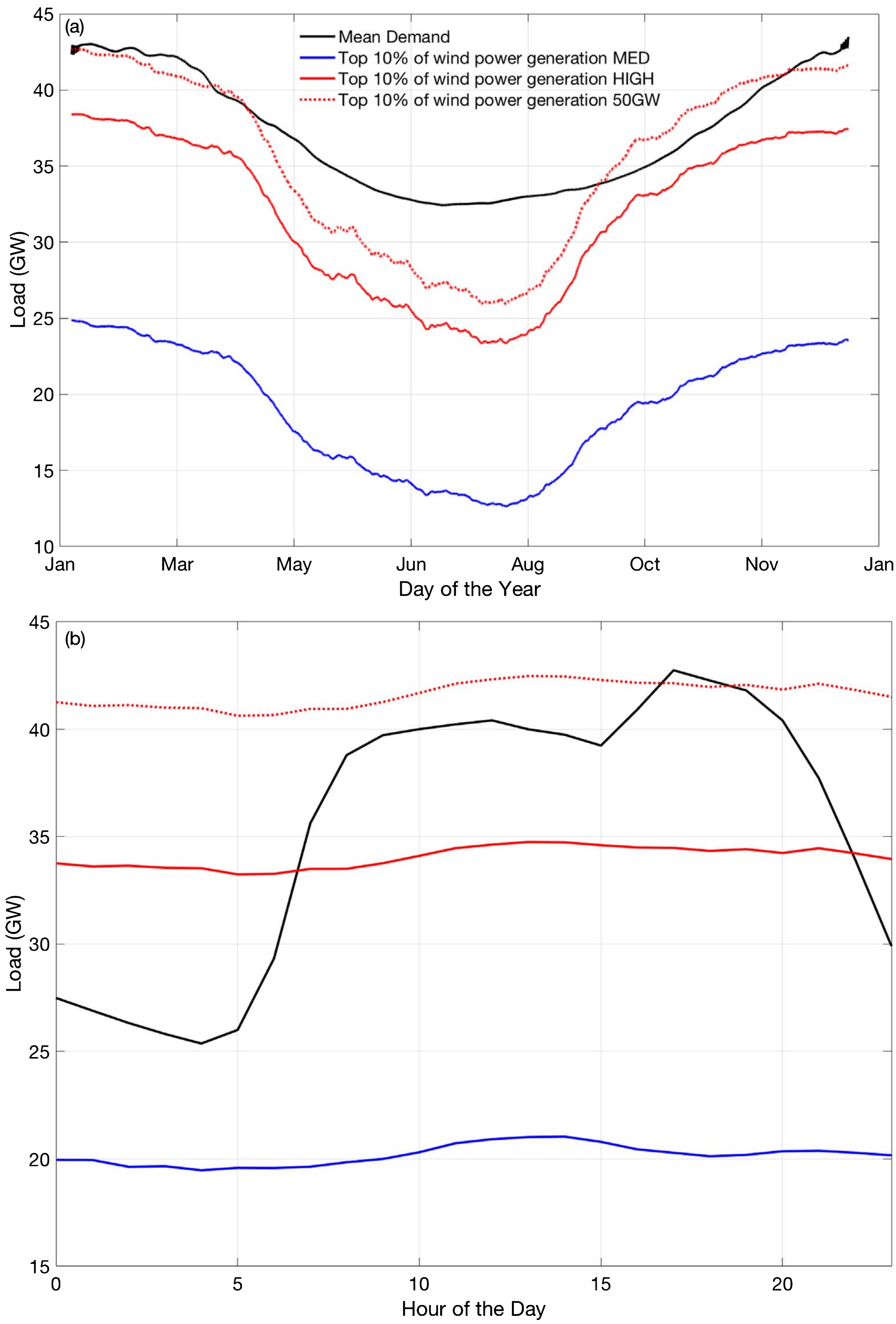

Figure 8. (*a*) Annual-mean cycle GB demand (black) and the 90th percentile of wind power generation in the MED (blue), HIGH (red) and 50GW of installed wind power (red dotted) scenarios, for the period 1980–2015. Data is processed with a running mean of 1 week for demand, and 1 month for wind power generation. (*b*) Diurnal cycle of Autumn-mean demand (black), the 90th percentile of autumn-mean wind power generation for the scenarios shown in (*a*).

levels which may lead to European-scale scarcity of supply. The annual-mean 10 m wind speed anomalies associated with TAER extremes (particularly high extremes) are, however, more localised to GB and the North Sea (figure 4), therefore there would not necessarily be a European excess or shortfall of wind power generation. This suggests that pan-European planning and interconnection of renewables could help to manage the inter-annual variability of TAER, as discussed in [14, 15 and 29].

The well established relationship between the GB power system and the NAO (see [7, 9, 11]) was confirmed in this study. However, this study has added to the literature by showing that although the correlation between TAER and the NAO is similar in all scenarios, the amount of wind power capacity installed on the

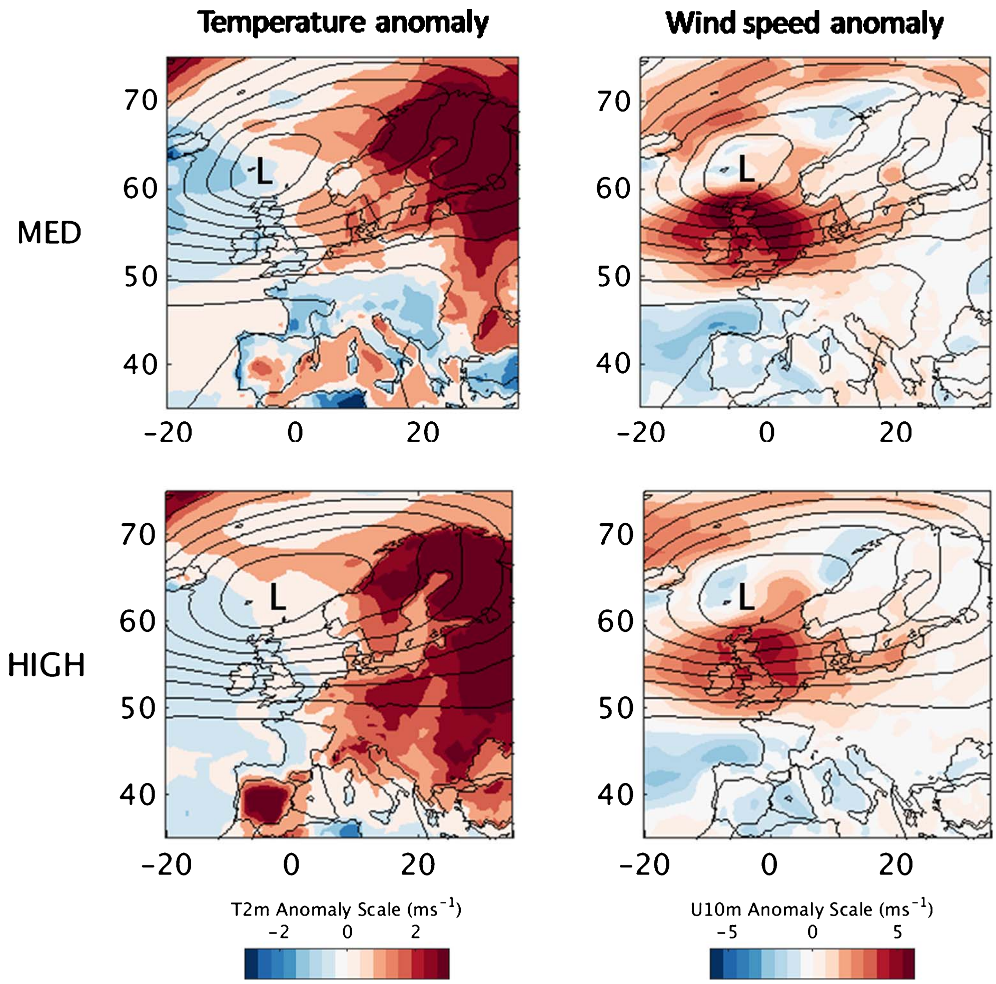

Figure 9. Anomaly composites of daily-mean data from the 1980–2015 autumn-mean of the ten most extreme wind power curtailment events for 2 m temperature (first column) and 10 m wind speed (2nd column) for the NO-WIND, LOW, MED and HIGH scenarios. Mean-sea-level-pressure contours are given in black, with a contour interval of 4hPa. The 'L' represents the centre of the low pressure system.

system has a large influence on the relative magnitude of the impact of an extreme NAO year. This suggests that large scale modes of climate variability will have growing significance for the power systems of GB and Europe more widely. The benefits of an accurate seasonal NAO forecast could be of increased importance in the future.

This work has highlighted the weather and climate conditions associated with extreme GB power system events. Specific synoptic situations can highlight the risk of scarcity of supply (associated with peak demand) or issues with grid stability (associated with wind power curtailment). This work also highlights the importance of a good representation of specific meteorological phenomena in climate datasets (whether from observations, reanalysis or climate simulations) if they are to be used as an input for power system simulations.

Acknowledgments

This research was funded by the Natural Environmental Research Council (NERC) under Grant 1362178.

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